ASSOCIATION OF BUSINESSES ADVOCATING TARIFF EQUITY

COMMENTS OF THE ASSOCIATION OF BUSINESSES ADVOCATING TARIFF EQUITY ON DRAFT REPORT DATED SEPTEMBER 20, 2013: "*READYING MICHIGAN TO MAKE GOOD ENERGY DECISIONS: RENEWABLE ENERGY*"

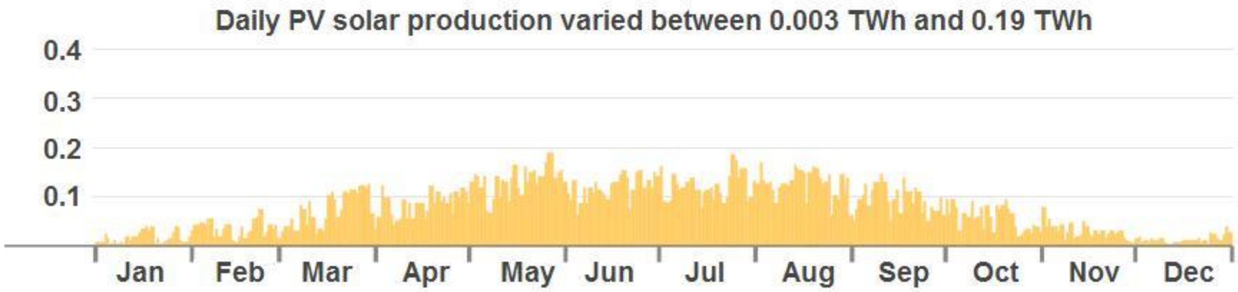
EXECUTIVE SUMMARY

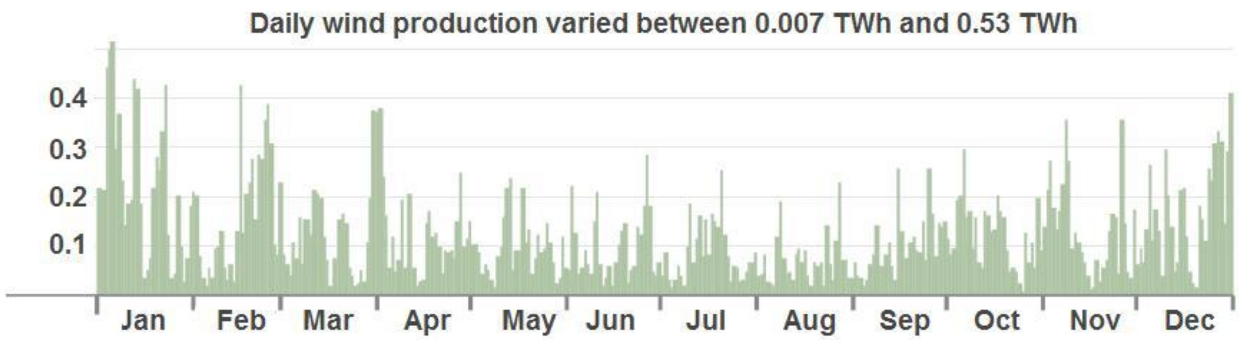
Effective October 6, 2008, Michigan utilities, cooperatives, and alternative electric suppliers were required to phase-in retail sales supplied from renewable energy resources. In addition, utilities having 1 million or more customers were required to either build or have under contract a minimum of 500 MW of renewable energy systems by December 31, 2015. Utilities appear to be well on their way to meeting these statutory mandates, but they have not acquired the full amount of capacity nor have they completed the phase-in of renewable energy resources necessary to supply the required 10% of sales by the end of 2015. Accordingly, Michigan does not have **any** actual experience regarding the impact of the full set of statutory renewable energy requirements.

To date, most of the renewable energy projects operating or currently under development are wind projects. Based on the cost data in the report, the levelized cost of wind generation is more expensive than generation from a natural gas conventional combined cycle plant. A logical conclusion is that "but for" the statutory mandate, Michigan utilities would not have voluntarily acquired these renewable wind energy resources in the amount specified in the statute in order to serve their loads due to cost and operational issues. Wind and solar produce power only when wind and sunlight are present and, therefore, are generally considered "intermittent" resources and not always available to serve customers. The Midcontinent Independent System Operator ("MISO") periodically publishes the percentage of nameplate capacity of wind resources that will be considered to be available "on peak" when the need for electricity is the greatest. According to MISO, the system-wide capacity credit for wind is 13.3%, and the actual credit in Zone 7 (Michigan's Lower Peninsula) is 11.0%.[1]

Germany, which has been at the forefront of adding renewable generation is a good example. "The graphs below demonstrate the problem (these are taken from a comprehensive report published by the Fraunhofer Institute).

[1] MISO: *Planning Year 2013-2014 Wind Capacity Credit, December 2012.*





The variability of wind production is such that there are many times when virtually no generation from wind is occurring - sometimes only for a few minutes, sometimes for many consecutive hours. PV solar generation also displays a great deal of variability and of course is not available after sunset when electricity demand is still quite high. The seasonal variation of PV generation in Germany is even more disturbing with winter values less than a quarter of summer values.

With renewable generation varying by an order of magnitude across the seasons and sometimes within a few hours at night how has the German electrical sector managed to keep the lights on? By depending upon traditional thermal generating assets which must be kept fully operational as "spinning reserves" that are available at all times to back-up renewable sources."[2] The draft renewable energy report did not adequately explore the cost and system operational issues related to wind and solar renewable resources.

Due to these complex cost and operational issues, the addition of new renewable generation cannot be considered in a vacuum. Any new mandates could result in excess capacity because the State is not engaged in a comprehensive Integrated Resource Planning ("IRP") process. For example, capacity addition appears to be imminent, such as Consumers Energy Company's 700 MW gas-fueled combined cycle plant, which is under consideration in Case No. U-17429. In Case No. U-17429, the Commission is required to make a determination whether or not to issue a Certificate of Necessity in April, 2014 which could pre-approve $750 million in construction costs. Unless there is a fully considered IRP for the State, the result may be a surplus of capacity from a combination of this gas-fueled plant plus any additional renewable energy capacity requirements. This is simply a result that the State cannot afford.

[2] *Germany at the Crossroads* (Authored by Davis Swan, October 1, 2013)

The State should engage in a robust IRP process before any major new capacity commitments are made or there are changes in the renewable energy mandates. The key driver in all of these considerations is whether the State needs new capacity and, given the high Michigan retail rates that currently exist, how any new capacity additions can help reduce the future retail cost of electricity in Michigan.[3] Michigan cannot afford to look at the various energy-related issues "piecemeal" and make decisions on less than comprehensive data.

IRP

ABATE needs a robust planning process before any future decisions are made with respect to the acquisition of new capacity resources to serve the electric needs of Michigan citizens and businesses. The dollar amounts associated with new investments are massive, regardless of the type of resource being considered. The new state-of-the-art gas-fueled generating plant is estimated to cost $750 million. Investment in renewable energy to date has cost hundreds of millions of dollars. The utility incentives alone, much less the cost of the energy optimization programs operated by utilities, are scheduled to cost $85 million.

The IRP process has been described as follows:

> Begun in the 1980s, Integrated Resource Planning is a tool to ensure that the utilities, regulators and other stakeholders have a common understanding of a full spectrum of possible utility resources; that the options are examined in a structured, disciplined way in administrative proceedings; that demand-side resources get equal consideration alongside supply-side resources; and that the final resource plan is understood (if not necessarily accepted) by all.[4]

One of the key goals of an IRP is to manage the risk faced by utilities and the stakeholders. These risks include over-investment, electricity shortages, obsolescence, technical failure, customer acceptance rates, etc. An effective IRP process should manage these risks for the benefit of all stakeholders.

According to **Ceres**, which leads a national coalition of investors, environmental groups and other public interest organizations working with companies to address sustainability challenges, the main elements of an effective IRP process include the following:

- The IRP must be meaningful and enforceable with something valuable at stake for the utilities and other parties;

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[3] *See,* attached rate comparisons demonstrating Michigan's high electric costs.
[4] *Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know,* (Authored by Ron Binz, Richard Sedano, Denise Furey, Dan Mullen, A Ceres Report, April 2012) p. 40.

- It must model multiple scenarios that review a wide variety of portfolio choices at different costs, risks, generation characteristics, fuel mixes, levels of energy efficiency, types of resources, sensitivity to changes in fuel cost, etc.;

- Must be developed under consistent, active regulation, coupled with performance monitoring;

- Must involve broad stakeholder investment in order to get the buy-in of as many diverse interest groups as possible;

- Involve a planning process that is transparent;

- Result in some form of competitive bidding for all resources to be acquired by the utility; and

- Fully consider the appropriate levels of energy efficiency.[5]

Act 295 acknowledges the need for an IRP process; however, it does not provide enough guidance and structure to be meaningful. ABATE suggests that the following should be used as a guideline for developing IRP legislation for the State of Michigan:

Michigan needs a supply planning process that makes planning more open to relevant government agencies, consumer groups, and others, thus considering the needs and ideas of all parties with a stake in the future of the electric system. For instance, as part of a supply planning process, in determining the type of new generation capacity to be built, the cost per kW of capacity, the cost per kWh of generation output, and the cost of transmission inter-connection should be calculated for each option, along with a weighing of the reliability and operational considerations (run-time availability/capacity factor, useful asset life, fuel diversity, etc.). The supply planning process should also require utilities to include a review of utilizing combined heat and power ("CHP") which would be installed at or near customer facilities generating electric power and utilizing thermal energy for various combinations of industrial processes, space and water heating and cooling applications, etc. CHP is generally twice as efficient as conventional generation facilities and is made possible at its basic level because of an industrial or commercial businesses' need for non-electrical thermal energy output. This represents one significant way by which the State could assist its large industrial customers with managing energy costs while providing a least-cost method to meet the State's energy needs.

Energy efficiency options should be included in a consideration of the available options. Prescriptive programs for industrial customers should be avoided, as should the payment of incentives to utilities to promote these programs to the tune of $85 million to date.

ABATE urges that one of the recommendations coming from this process is for new legislation requiring a state-wide IRP process to be followed by competitive bidding for the supply of the total resource instead of only major components. Also, following the lead of

[5] *Id*, at pp. 41-42.

MISO, the planning process could involve two distinct zones, consisting of the Upper and Lower Peninsulas.

ABATE stands ready to work with other stakeholders to develop a workable IRP legislative proposal that will result in the efficient and cost-effective acquisition of needed resources to serve the needs of all Michiganders.

2012 - 2013 Residential Electric Rates for Investor Owned Utilities 1,000 kWh Consumption

Illinois, Indiana, Iowa, Kentucky, Michigan, Minnesota, Missouri, Ohio, Wisconsin

Line	Utility	State	¢/kWh*
1	Madison Gas & Electric Company	WI	15.24
2	Southern Indiana Gas & Electric Company	IN	15.17
3	**DTE Electric Company**	**MI**	**15.07**
4	We Energies (formerly Wisconsin Electric)	WI	14.20
5	Dayton Power & Light Company	OH	13.41
6	AEP (Columbus Southern Power Rate Area)	OH	13.27
7	Northern Indiana Public Service Company	IN	12.92
8	**Consumers Energy**	**MI**	**12.79**
9	Interstate Power & Light	IA	12.79
10	Wisconsin Public Service Corporation	WI	12.63
11	AEP (Ohio Power Rate Area)	OH	12.40
12	WP&L	WI	12.09
13	Northern States Power Company (WI)	WI	11.99
14	Northern States Power Company (MN)	MN	11.98
15	Ohio Edison Company	OH	11.93
16	Commonwealth Edison Company	IL	11.81
17	Cleveland Electric Illuminating Company	OH	11.67
18	Toledo Edison Company	OH	11.63
19	Empire District Electric Company	MO	11.34
20	Kansas City Power & Light - MPS (formerly Aquila)	MO	11.30
21	Kansas City Power & Light - L&P (formerly Aquila)	MO	11.24
22	Duke Energy Ohio	OH	11.19
23	Duke Energy Indiana	IN	10.99
24	Ameren Illinois Rate Zone III (formerly IP)	IL	10.18
25	Kansas City Power & Light Company	MO	10.13
26	AEP (Indiana Michigan Power combined MI rate areas)	MI	10.02
27	Minnesota Power Company	MN	9.77
28	Indianapolis Power & Light Company	IN	9.70
29	Louisville Gas & Electric Company	KY	9.27
30	AmerenUE	MO	9.26
31	Ameren Illinois Zone II (formerly CILCO)	IL	9.23
32	Ameren Illinois Rate Zone I (formerly CIPS)	IL	9.13
33	MidAmerican Energy	IA	9.02
34	Duke Energy Kentucky	KY	8.98
35	AEP (Kentucky Power Rate Area)	KY	8.93
36	Kentucky Utilities Company	KY	8.69
37	AEP (Indiana Michigan Power)	IN	8.60

* Weighting = Four (4) 2012 Summer Months and Eight (8) 2013 Winter Months
Illinois utilities with open access are excluded.

Source: Edison Electric Institute Typical Bills and Average Rates Reports.

Residential 1 / 3

2012 - 2013 Commercial Electric Rates for
Investor Owned Utilities
500 kW Demand and 150,000 kWh Consumption

Illinois, Indiana, Iowa, Kentucky, Michigan, Minnesota, Missouri, Ohio, Wisconsin

Line	Utility	State	¢/kWh*
1	AEP (Columbus Southern Power Rate Area)	OH	12.02
2	Madison Gas & Electric Company	WI	11.67
3	We Energies (formerly Wisconsin Electric)	WI	11.58
4	**DTE Electric Company**	**MI**	**11.57**
5	AEP (Ohio Power Rate Area)	OH	11.14
6	Northern Indiana Public Service Company	IN	10.98
7	Dayton Power & Light Company	OH	10.86
8	**Consumers Energy**	**MI**	**10.12**
9	Northwestern Wisconsin Electric Company	WI	9.92
10	Duke Energy Ohio	OH	9.71
11	Northern States Power Company (MN)	MN	9.63
12	AEP (Indiana Michigan Power combined MI rate areas)	MI	9.49
13	Northern States Power Company (WI)	WI	9.45
14	Interstate Power & Light	IA	9.36
15	WP&L	WI	9.30
16	Duke Energy Kentucky	KY	9.22
17	Louisville Gas & Electric Company	KY	9.18
18	Empire District Electric Company	MO	9.18
19	Ameren Illinois Rate Zone III (formerly IP)	IL	9.14
20	Southern Indiana Gas & Electric Company	IN	8.93
21	Duke Energy Indiana	IN	8.81
22	Kansas City Power & Light - L&P (formerly Aquila)	MO	8.80
23	Ameren Illinois Zone II (formerly CILCO)	IL	8.76
24	Indianapolis Power & Light Company	IN	8.75
25	AEP (Kentucky Power Rate Area)	KY	8.73
26	Wisconsin Public Service Corporation	WI	8.71
27	Ameren Illinois Rate Zone I (formerly CIPS)	IL	8.57
28	Kansas City Power & Light Company	MO	8.38
29	Ohio Edison Company	OH	8.28
30	Cleveland Electric Illuminating Company	OH	8.28
31	Minnesota Power Company	MN	8.16
32	AEP (Indiana Michigan Power)	IN	8.02
33	Toledo Edison Company	OH	7.89
34	Kansas City Power & Light - MPS (formerly Aquila)	MO	7.69
35	Kentucky Utilities Company	KY	7.48
36	AmerenUE	MO	7.30
37	MidAmerican Energy	IA	5.97

* Weighting = Four (4) 2012 Summer Months and Eight (8) 2013 Winter Months
Illinois utilities with open access are excluded.

Source: Edison Electric Institute Typical Bills and Average Rates Reports.

Commercial 2 / 3

2012 - 2013 Industrial Electric Rates for
Investor Owned Utilities
50,000 kW Demand and 25,000,000 kWh Consumption

Indiana, Iowa, Kentucky, Michigan, Minnesota, Missouri, Ohio, Wisconsin

Line	Utility	State	¢/kWh*
1	Madison Gas & Electric Company	WI	9.10
2	We Energies (formerly Wisconsin Electric)	WI	8.67
3	**DTE Electric Company**	**MI**	**8.25**
4	Northern States Power Company (MN)	MN	7.68
5	Southern Indiana Gas & Electric Company	IN	7.61
6	Dayton Power & Light Company	OH	7.49
7	**Consumers Energy**	**MI**	**7.40**
8	Empire District Electric Company	MO	7.10
9	AEP (Indiana Michigan Power combined MI rate areas)	MI	7.04
10	Duke Energy Indiana	IN	6.98
11	Northern States Power Company (WI)	WI	6.90
12	Indianapolis Power & Light Company	IN	6.83
13	Kansas City Power & Light - L&P (formerly Aquila)	MO	6.72
14	WP&L	WI	6.68
15	Wisconsin Public Service Corporation	WI	6.63
16	AEP (Ohio Power Rate Area)	OH	6.53
17	Minnesota Power Company	MN	6.53
18	Ohio Edison Company	OH	6.49
19	Northern Indiana Public Service Company	IN	6.49
20	Cleveland Electric Illuminating Company	OH	6.45
21	Duke Energy Kentucky	KY	6.40
22	Toledo Edison Company	OH	6.26
23	Duke Energy Ohio	OH	6.23
24	AEP (Columbus Southern Power Rate Area)	OH	6.00
25	Kansas City Power & Light - MPS (formerly Aquila)	MO	5.94
26	Louisville Gas & Electric Company	KY	5.94
27	Kansas City Power & Light Company	MO	5.61
28	Interstate Power & Light	IA	5.61
29	AEP (Indiana Michigan Power)	IN	5.49
30	AmerenUE	MO	5.40
31	Kentucky Utilities Company	KY	5.25
32	AEP (Kentucky Power Rate Area)	KY	4.83
33	MidAmerican Energy	IA	4.44

* Weighting = Four (4) 2012 Summer Months and Eight (8) 2013 Winter Months
Illinois utilities with open access are excluded.

Source: Edison Electric Institute Typical Bills and Average Rates Reports.